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Integrating carbon capture and storage with energy production from saline aquifers: A strategy to offset the energy cost of CCS

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Abstract

Extraction of brine containing methane and geothermal energy from saline aquifers has been considered as a method to offset the cost of carbon capture and storage. This study estimates the potential of power generation from methane and heat and compares it with the power required for capture and storage. Nine aquifer models were prepared from average conditions of several wells in the Gulf Coast at depths from 8,000 to 16,000 ft. Reservoir simulation study was performed to estimate the amounts of stored carbon dioxide and produced methane and heat. The study found that the power generation potential from below the depth of 11,000 ft offsets the power required for capture and storage processes.

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Keywords: CO_2 capture and storage; dissolved methane; geothermal energy; geopressured-geothermal aquifers; surface dissolution

1. Introduction

Coal-fired power plants in the United States provide more than one-third of the power generated nationally and represents more than 30% of CO_2 emissions. Any reasonable mitigation strategy must reduce these carbon emissions without reducing the power output from these power plants. This requirement drives the main economic challenge of CCS. Current estimates are in the range of tens of dollars per metric ton of CO_2 leading to 30 to 50 percent increase in the electricity prices [1]. Most of this cost arises from the energy required for separating CO_2 from flue gas

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emitted from power plant and pressurizing it for storage. Amine scrubbing is the most developed technology for capturing CO_2 from flue gas. It is estimated that the energy required for capturing CO_2 by amine scrubbing [2] or chilled ammonia [3] and pressurizing it to supercritical conditions is about 30% of the output of the power plant. Also, the most recent conceptual designs of separation by membranes show that the required energy cannot be less than about 20% of the output of the power plant [4].

Ganjdanesh et al. [5,6] proposed a new storage strategy that could pay for itself. In this strategy, high temperature methane-saturated brine is extracted from storage formations. The methane and geothermal energy are extracted from the brine. The captured CO_2 and produced brine are mixed at surface and the mixture is injected into the aquifer for permanent storage. The injection improves the recovery of in-situ methane and geothermal energy, which could be sold or be used for carbon capture and storage. Moreover, Large-scale injections of bulk CO_2 carry several risks including pressure buildup [7], brine displacement [8], and CO_2 leakage through conductive pathways [9]. Thus, another advantage of the extraction of brine and injection of CO_2/brine mixture is that it eliminates or mitigates these risks [10].

Extremely large resources of dissolved methane and geothermal energy exist in geopressured/geothermal aquifers of the US Gulf Coast in Texas and Louisiana. These formations are characterized by high pressures and high temperatures. The abnormally pressured formations are mostly the result of compaction. Other mechanisms for overpressurization include clay dehydration and hydrocarbon maturation. The overpressured fluid causes higher than normal porosity and lower thermal conductivity. Therefore, the temperatures in geopressured formations tend to be higher than normal. Figure 1 shows the average bottomhole pressure and temperature for several wells in Lavaca County, Texas [11]. The temperature and pressure gradients are greater than normal below the depth of 10,000 ft, where the geopressured-geothermal formations begin. The temperature increases from 200 °F to more than 350 °F indicating the potential of production of geothermal energy.

The geopressured-geothermal resources of the Gulf Coast are well documented. During 70's and 80's, the Department of Energy conducted an extensive study on the geopressured-geothermal aquifers of the Gulf Coast as prospective sources of natural gas and geothermal energy. Several studies estimated that these aquifers contain on the order of thousands of trillion cubic feet (TCF) of dissolved methane [12]. Figure 2 shows the solubility of carbon dioxide and methane obtained from the thermodynamic models of Duan and Sun [13] and Duan and Mao [14]. At pressures and temperatures associated with geopressured-geothermal conditions, the solubility of methane is about 25 to 60 standard cubic feet per barrel of brine and the solubility of CO_2 is about an order of magnitude higher than the solubility of methane. Thus, the capacity of CO_2 storage in these aquifers is also remarkable.

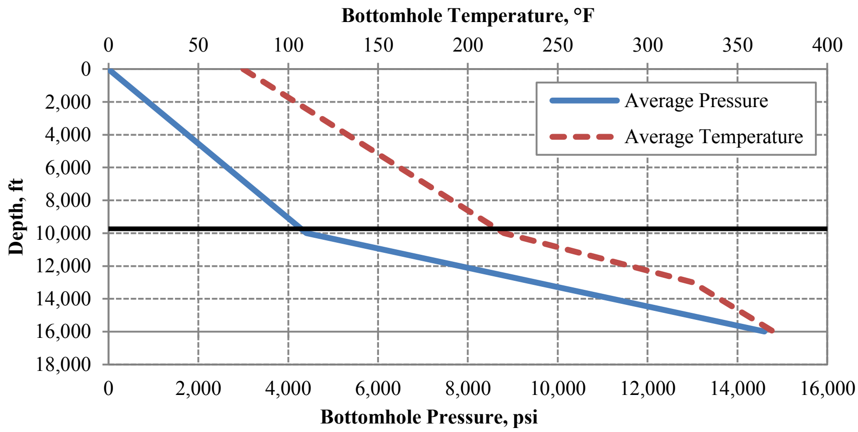

Figure 1: Average bottomhole pressure and temperature for 57 wells in Lavaca County, Texas.

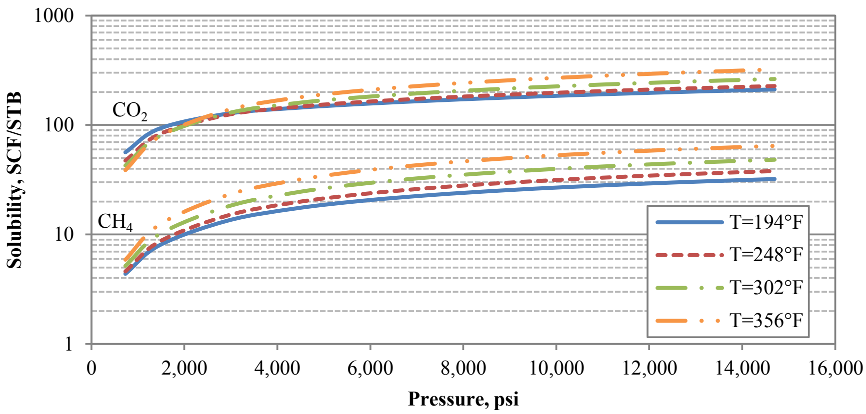

Figure 2: Solubility of CO_2 and CH_4 in 55,000 ppm brine.

Hydropressured aquifers may also contain dissolved methane and geothermal energy. All the aquifers contacted by gas during its migration toward the reservoir rock are largely saturated with methane. Figure 2 illustrates the solubility of methane in brine for wide ranges of pressures and temperatures. The observations from the ongoing CO_2 storage project in Cranfield [15] show that the brine of the water leg of the reservoir is saturated with methane and the temperature of the aquifer is about 260 °F. This is an example of methane saturated brine in hydropressured aquifers in the United States. However, the energy reserves in hydropressured aquifers in the United States have remained less investigated. Production of methane from deep saline aquifers has been undertaken in Russia [16] and Japan [17] for several decades.

The level of cost offset of CCS technology by producing energy from target aquifers depends on how the produced energy is used. The hot water could be used to run a binary cycle to produce electricity or be used for local heating purposes. The produced methane could be sold as a product or be used in a variety of cycles to generate electricity. Ganjdanesh et al. [18] proposed that the geothermal energy could be used to capture CO_2 by amine scrubbing since the temperature of the produced water is high enough to be used in reboiler of stripper column. Also, they suggested that the produced methane could be used to run the compressors and pumps to pressurize the CO_2 and brine.

This study explores the cost offset based on the average aquifer conditions for a wide range of depths in Texas Gulf Coast. Several aquifer models were built for numerical simulations at depths from 8,000 to 16,000 ft. The amount of produced methane/heat and injected CO_2/brine were estimated for all models. In this study, it was assumed that all the produced methane and heat are converted into electricity. Finally, the produced electricity was compared to the energy required for capture and pressurization of CO_2 and brine to find the most favorable aquifer conditions. The objective of this study was to determine whether the saline aquifers could provide enough energy to offset the power required for carbon capture and storage from coal-fired power plants. Although the models were built based on the average conditions of a limited number of wells in Texas, it is expected that the results are applicable to many methane-saturated aquifers in the Texas Gulf Coast.

2. Simulation models

Reservoir modelling and simulation were used to analyze the production of methane and hot brine from methane-saturated aquifers. Nine reservoir models were built at depths from 8,000 to 16,000 ft. The reservoir characteristics such as porosity, permeability, thickness, and areal size were selected from the typical ranges observed for the aquifers in the Gulf Coast [19,20,21]. Initial pressures and temperatures were selected from their correlations with depth from Figure 1. Salinity was assumed to be 55,000 ppm. Relative permeability curves and capillary pressure were built using Corey model. A parallel horizontal well pattern was chosen for injector and producer to achieve higher production rate and sweep efficiency. Figure 3 is a schematic of the aquifer model and well placement. The horizontal wells were placed at the edges of the aquifer model. The injection and production rates are half of the

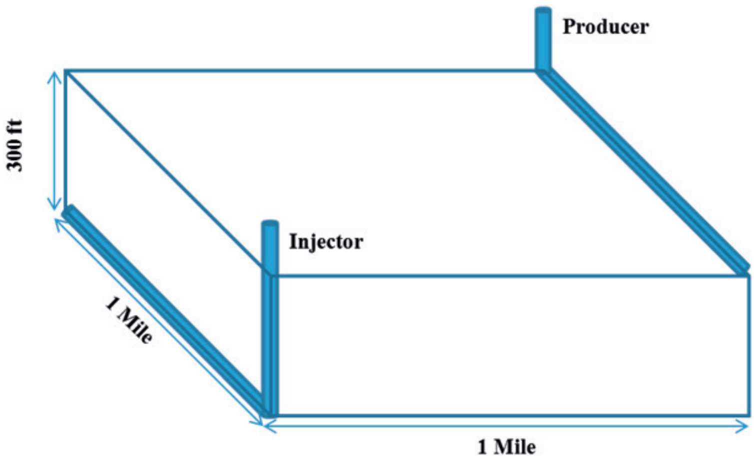

Figure 3: Schematic of an aquifer model with horizontal injection and production wells.

values for full wells in a repeated well pattern in an aquifer with the same properties as the aquifer model, which is a symmetry element. Well types and locations affect the time of CO_2 breakthrough and the fraction of the initial methane and brine in place that can be recovered before CO_2 breakthrough. If the CO_2-saturated brine is injected low in the aquifer to displace the CH_4-saturated brine upward, the displacement is gravity stable, although the effect of gravity is small for the case of brine displacing brine. The displacement and sweep efficiencies for brine displacing brine are high compared to gas displacing brine. The wells were placed 1 mile apart leading to the breakthrough of CO_2 after 20 years. Table 1 summarizes the characteristics of the nine aquifer models.

Table 1: Properties of unit cell for saline aquifers.

Length and width, ft	5280
Thickness, ft	300
Number of gridblocks	80×80×30
Gridblock size, ft	66×66×10
Depth at top of the formation, ft	8,000 – 16,000
Temperature, °F	190 - 370
Initial pressure, psi	3,600 – 14,600
Salinity, ppm	55,000
Porosity, %	20.0
Horizontal permeability, md	100
Vertical permeability, md	10

CMG's compositional numerical reservoir simulator GEM [22] was used to model the fluid and geological complexities of the process. The Peng-Robinson equation-of-state (PREOS) was used to model the fluid containing carbon dioxide, methane and brine. The PREOS parameters were tuned to fit the experimental data under aquifer conditions. GEM's wellbore model was used to relate the bottomhole pressures and fluid rates with wellhead pressures.

3. Simulation results

The main outputs of interest from reservoir simulations are the flow rates of produced methane and brine, wellhead pressure of injector, and the flow rates of injected CO_2 and brine. It was assumed that the temperature of the produced brine decreases to 95 °F in a binary cycle. The mixture of CO_2 and produced brine is injected into the same aquifer. The mole fraction of CO_2 in the injected fluid is 2.5% for all nine cases. Therefore, the amount of required brine to store one metric ton of CO_2 is 16.6 ton, which is equivalent to 100 stock tank barrel (STB). The injection rates of CO_2 and brine are 380 metric tons and 38,000 STB per day and are similar for all nine cases.

Table 2 summarizes the injection and production rates for all nine cases. The brine production rates are about 40,000 STB per day. The methane production rate increases from 600 MSCF per day at 8,000 ft to 2,500 MSCF per day at 16,000 ft, reflecting the greater solubility of methane at greater depths. The wellhead pressures of producers are 300 psi for all cases. The wellhead pressures of injectors and producers are plotted versus depth in Figure 4.

Table 2: Injection and production rate for all cases.

Depth (ft)	Initial pressure (psi)	Initial temperature (°F)	Brine injection rate (STB/Day)	CO_2 injection rate (Ton/Day)	CH_4 production rate (SCF/Day)	Brine production rate (STB/Day)
8,000	3,600	190	38,300	380	605,000	39,500
9,000	4,000	205	38,300	380	669,000	39,500
10,000	4,400	220	38,300	380	749,000	39,500
11,000	6,100	255	38,300	380	992,000	39,800
12,000	7,800	290	38,300	380	1,264,000	40,200
13,000	9,500	325	38,300	380	1,586,000	40,700
14,000	11,200	340	38,300	380	1,824,000	41,100
15,000	12,900	355	38,300	380	2,080,000	41,500
16,000	14,600	370	38,300	380	2,454,000	41,900

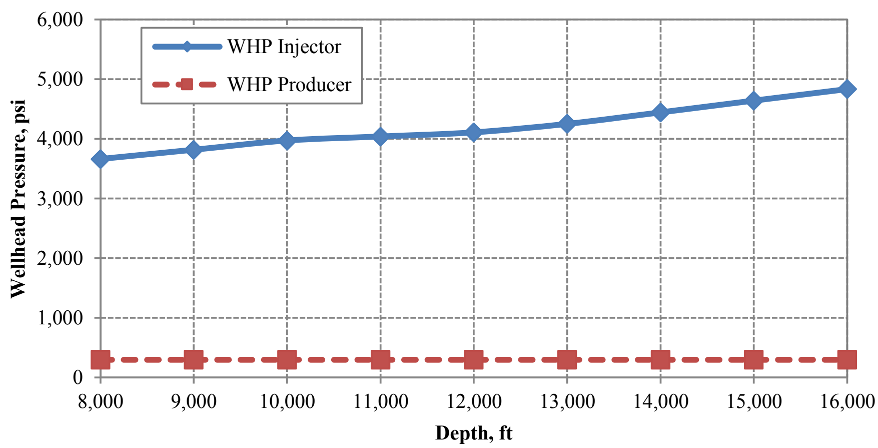

Figure 4: Wellhead pressure of injectors and producers.

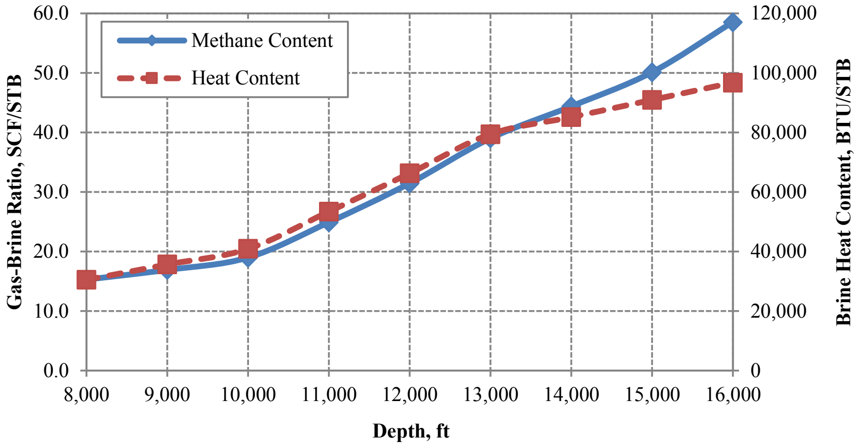

Figure 5: Methane and heat content of one stock tank barrel of produced brine.

The produced gas is separated from brine at surface facilities and the produced brine passes through a heat exchanger to transfer heat from the produced fluid to the working fluid of a binary Organic Rankine Cycle (ORC). The heat input to the ORC power plant is calculated from the change in enthalpy of the produced brine between the inlet and outlet of the heat exchanger,

$$\dot{Q} = \dot{m}\left[H_{T_{in}} - H_{T_{out}}\right]. \tag{1}$$

The temperature drop in the heat exchanger and additional pressure drop in surface facilities cause more methane exsolution from brine. Assuming outlet temperature and pressure of 95 °F (35 °C) and 50 psi, the estimated amount of extracted heat and methane from one stock tank barrel of produced brine is shown in Figure 5.

4. Energy analysis

The process of injection and production was scaled up to investigate the energy balance for the CCS process of a 500 MW power plant combined with energy production from the aquifer. The energy required for the operation of each part of the process was analyzed separately. Also, the produced energy from methane and hot brine was estimated.

The average CO_2 emission rate from a 500 MW power plant is estimated to be 10,000 metric tons per day. The capture process and pressurization are the major energy consumers. The pressurization process includes the compression of CO_2 and pumping the brine to the wellhead pressure of injectors. The power required for compression of CO_2 to mixing condition is calculated using the polytropic equation,

$$\dot{W}_{CO_2} = \frac{S\dot{N}_{CO_2}nRT_1}{(n-1)}\left(\left(\frac{P_{mixing}}{P_1}\right)^{\frac{n-1}{nS}} - 1\right), \tag{2}$$

where the number of compressor stages (S) is 10 and the polytropic constant (n) is calculated by

$$n = \frac{k\eta_p}{1 + k\eta_p - k}. \tag{3}$$

The polytropic efficiency (η_p) is 80% and the ratio of specific heats (k) for CO_2 is 1.30.

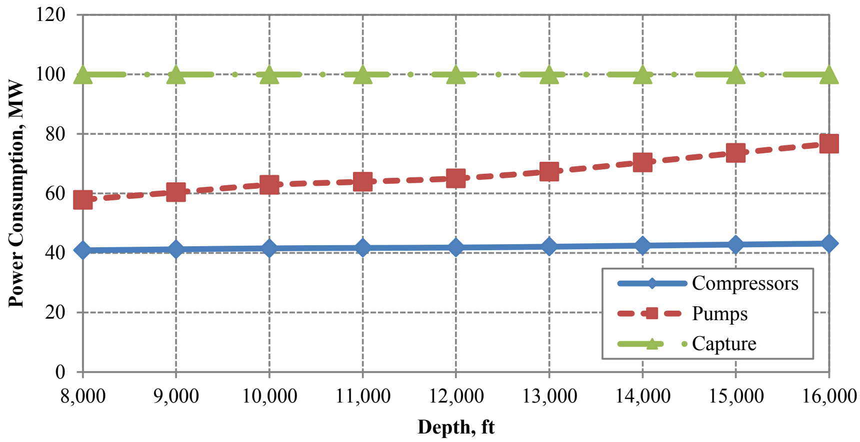

Figure 6: Power consumption by compressors, pumps, and capture units.

About 1,000,000 STB of brine per day should be pumped from 50 psi to wellhead pressure of injectors. The power required to pump the brine up to mixing condition is calculated using the mechanical energy balance equation,

$$\dot{W}_{Brine} = \frac{q_{Brine}\left(P_{mixing} - P_1\right)}{\eta_{Pump}}, \tag{4}$$

where the pump efficiency (η_{pump}) is 80%. In order to inject at these rates, 13 injectors and 13 producers are needed.

The other power consumer part of the process is the CO_2 capture from flue gas. Van Wagener et al. [23,24] analyzed the energy requirement for two amine solutions in CO_2 capture by chemical absorption as the most reliable candidates for a commercial capture process. The results indicated that the capture process consumes about 20% of the output of the power plant. Thus, about 100 MW power is taken from a 500 MW power plant. Figure 6 shows the power consumption for each process.

The heat transferred from the produced hot brine to the working fluid of the ORC power plant is converted into useful work by passing the working fluid through a turbine or other kind of expanders that can itself be converted into electricity. The efficiency of the ORC cycle depends on the inlet and outlet temperature of the source fluid. One analysis [25] of the US electricity generation potential led to a correlation for the thermal efficiency (η_{th}). This correlation was derived from data for existing ORC geothermal power plants based on the temperature of hot brine,

$$\eta_{th} = \frac{\dot{W}}{\dot{Q}} = 0.0935T(°C) - 2.3266, \tag{5}$$

where the heat input to the power plant is calculated from Eq. 1 and the outlet temperature is assumed to be 95 °F. Also, the produced methane can be converted into useful work through a gas cycle power plant or gas engine. The gross rate of produced energy is calculated based on the heat of combustion of methane. The efficiency of gas cycles vary between 30 to 60 percent depending on the technology. It is suggested that the methane could be burned in gas engines with efficiencies as high as 47 percent. Table 3 summarizes the amounts of produced energy and useful work from methane and hot brine for all cases. Figure 7 shows the total produced power for all cases.

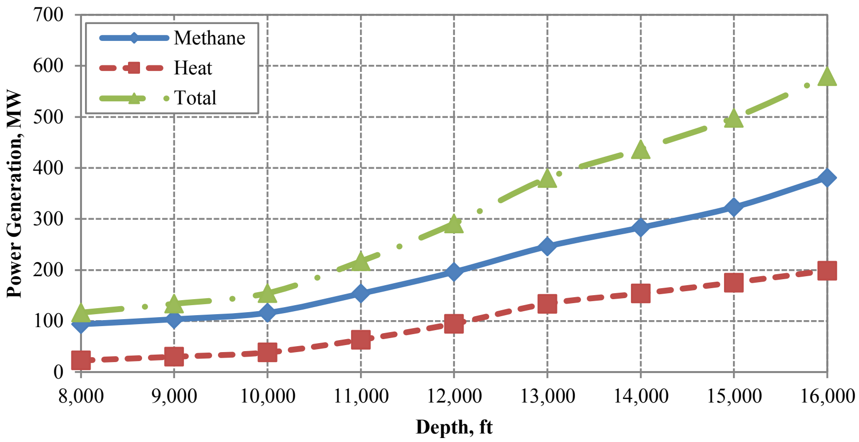

Figure 7: Electric power generation by methane and heat and total power generation potential.

Table 3: Electric power generation from methane and hot brine.

Depth (ft)	CH_4 production (MMSCF/Day)	Brine production (MMSTB/Day)	CH_4 gross power (MW)	Brine gross power (MW)	Gas cycle efficiency (%)	Thermal efficiency (%)	CH_4 useful power (MW)	Brine useful power (MW)
8,000	15.9	1.040	200	388	47.0	5.9	94	23
9,000	17.6	1.039	221	453	47.0	6.7	104	30
10,000	19.7	1.037	247	519	47.0	7.4	116	39
11,000	26.1	1.048	328	684	47.0	9.3	154	63
12,000	33.3	1.058	418	856	47.0	11.1	196	95
13,000	41.7	1.070	524	1038	47.0	12.9	246	134
14,000	48.0	1.081	602	1125	47.0	13.7	283	154
15,000	54.7	1.093	687	1214	47.0	14.5	323	175
16,000	64.6	1.103	811	1304	47.0	15.2	381	199

Finally, Figure 8 illustrates the total produced power by methane and hot brine and the total consumption by compressors, pumps, and capture units. The net power is calculated by subtracting the total consumption from total generation. The total power consumption for capture and storage is less sensitive to depth compared to the total power generation. The power generation increases rapidly by penetrating into the geopressured-geothermal zone below the depth of 10,000 ft. The calculations show that the net power at 8,000 ft is about -82 MW, which is about 16.4% of the output of a 500 MW power plant. The power consumption is completely offset by generation at about 11,000 ft. Thus, the process can produce a positive balance below a depth of 11,000 ft. The net power is +84 MW at 12,000 ft, and +360 MW at 16,000 ft, which are in addition to the 500 MW output of the power plant.

5. Conclusions

Integration of carbon capture and storage with energy production from deep saline aquifers is a new and promising idea. There is a significant potential for offsetting the cost of CCS by producing large quantities of methane and geothermal energy. This study developed methane-saturated aquifer models for nine depths between 8,000 and 16,000 ft by use of average data of aquifers in the U.S. Gulf Coast. The injection and production scenarios, well spacing, and well rates were designed based on storing 10,000 ton CO_2 per day for 20 years without injected CO_2 reaching production wells. It was assumed that a mixture of extracted brine and CO_2 is injected with a

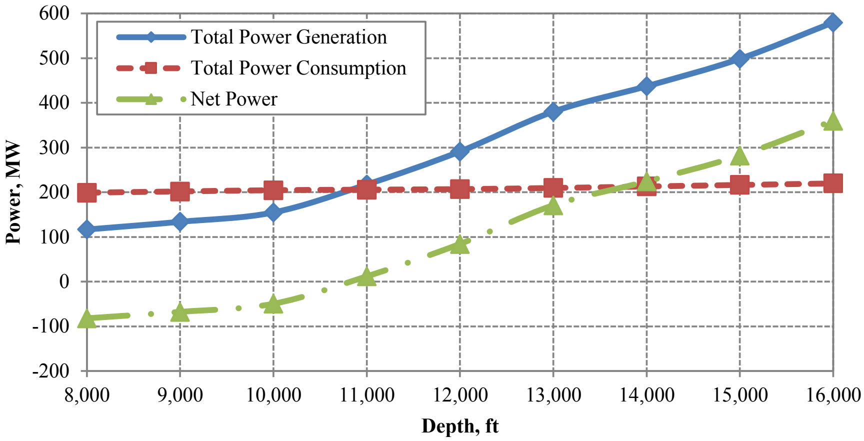

Figure 8: Total power generation and consumption and net power of the integrated cycle of production, capture, and storage.

ratio of 100 barrels per metric ton CO_2. The energy analysis assumed that Organic Rankine Cycle and gas engine could be used to convert the extracted energy into power. Power consumption is much less sensitive to depth than power generation. Thus, the energy offset increases rapidly with depth. The generated power completely offsets the consumed power for geopressured-geothermal storage formations below a depth of 11,000 ft. The designed closed-loop cycle is capable of adding to the output of the power plant by storing CO_2 at depths representing geopressured-geothermal conditions. The net power is 360 MW at 16,000 ft, which is in addition to the 500 MW output of the power plant.

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